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September 6, 2006

Mary L. Cottrell, Secretary
Department of Telecommunications and Energy
One South Station, 2nd Floor
Boston, MA 02110

Re: NSTAR Electric Company, D.T.E. 06-40

Dear Secretary Cottrell:

Enclosed for filing is the NSTAR Electric Initial Brief in the above-referenced case. Also enclosed is a Certificate of Service.

Thank you for your attention to this matter.

Sincerely,

Robert N. Werlin

Robert N. Werlin

Enclosures

cc: Joan Foster Evans, Hearing Officer
Service List

COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

Boston Edison Company, Cambridge Electric Light Company, Canal Electric Company and Commonwealth Electric Company d/b/a NSTAR Electric	)	D.T.E. 06-40

CERTIFICATE OF SERVICE

I certify that I have this day served the foregoing document upon the Department of Telecommunications and parties of record in accordance with the requirements of 220 C.M.R. 1.05 (Department's Rules of Practice and Procedures).

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Dated: September 6, 2006

COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

	)	
Boston Edison Company, Cambridge Electric	)	
Light Company, Canal Electric Company and	)	D.T.E. 06-40
Commonwealth Electric Company d/b/a NSTAR Electric	)	
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INITIAL BRIEF OF BOSTON EDISON COMPANY, CAMBRIDGE ELECTRIC LIGHT COMPANY, CANAL ELECTRIC COMPANY AND COMMONWEALTH ELECTRIC COMPANY

Respectfully Submitted,

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Dated: September 6, 2006

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EXECUTIVE SUMMARY

In 1999, the holding companies for Boston Edison Company ("Boston Edison"), Cambridge Electric Light Company ("Cambridge"), Canal Electric Company ("Canal") and Commonwealth Electric Company ("Commonwealth"; together, the "Companies") merged and created NSTAR. Because of various practical and legal impediments, the four electric companies could not legally merge at that time. However, the operations of the Companies were integrated, creating the synergies that have resulted in hundreds of millions of dollars in customer savings. See Boston Edison/Commonwealth Energy System Merger, D.T.E. 99-19 (1999); NSTAR Merger Savings Report, D.T.E. 04-2 (2004). Now that the practical and legal impediments that delayed the merger of the Companies no longer prevent full consolidation, it is time to remove the legal fiction that the Companies operate as separate business entities. As described below, the formal corporate merger of the Companies will further streamline administrative and regulatory operations, reduce customer confusion and improve customer service.

The public-interest statutory standard for approval of a merger by the Department of Telecommunications and Energy (the "Department"), pursuant to G.L. c. 164, § 96, does not require a demonstration of net benefits to customers, but only that there be no net harm to customers. Nonetheless, the record in this case shows that the merger of the Companies will impose no costs on customers, and that (although difficult to quantify with precision) the customer benefits will be meaningful. For example, reducing the number and complexity of regulatory filings will lead to more transparency in the Companies' operations, better customer understanding and improved regulatory oversight. The continuation of unnecessary cost-allocation processes and reporting requirements for entities that, operationally, are already merged, makes no sense and can be reduced significantly with the approval of the merger. Over a decade ago, the Department adopted regulatory policies designed to encourage mergers and consolidations and determined that:

> …in light of concerns over high utility rates which in part may be the result of duplicative facilities, functions, and services among Massachusetts utilities, the Department has sought to reexamine its current policy towards mergers or acquisitions and determine whether the public interest may better be served by specific policy changes that enhance efficient delivery of utility services in Massachusetts….[T]he Department believes that cost-effective mergers are one of several means by which utilities may be able to reduce their cost of service, improve service reliability, and enhance their financial strength.

Mergers and Acquisitions, D.P.U. 93-167-A at 4-5 (1994). Given the absence of customer costs relating to this "internal" merger of the Companies, the Companies have demonstrated that the proposed merger is consistent with the Department's merger policies and meets the statutory no-net harm standard as applied by the Department.

Not only will the final corporate step in the consolidation of the Companies (i.e., formal merger) complete the formal merger actions contemplated in D.T.E. 99-19, but it will implement the provisions of the Settlement Agreement approved by the Department last year in D.T.E. 05-85. That Settlement Agreement expressly provided for the merger of the Companies, subject to Department and FERC regulatory proceedings (Settlement Agreement at ¶ 2.16), and established certain implementation requirements and/or limitations relating to the merger. For example, the Settlement Agreement required that distribution and transition rates for customers of Boston Edison, Cambridge and Commonwealth be separately maintained, so that the rate changes of the Settlement Agreement be implemented (Settlement Agreement at ¶ 2.17). Conversely, the consolidation of transmission rates was expressly acknowledged, and the Companies agreed that Cambridge's 13.8 kilovolt ("kV") facilities would be reclassified as distribution and recovered in distribution rates (Settlement Agreement at ¶ 2.18).[1] In addition, the Department-approved Settlement Agreement provides for the setting of uniform depreciation rates for the Companies at the time of the merger (Settlement Agreement at ¶ 2.6.2). Only the exact formula to implement "uniform depreciation rates that are expense neutral at the functional group level…" was left to later determination.[2] The Companies have demonstrated that they have complied with the terms of the Settlement Agreement and proposed reasonable mechanisms to implement its terms.

In addition to the implementation of the rate provisions of the Settlement Agreement, the Companies have proposed consolidation of two other retail rates: Basic Service (including the Basic Service Adder) and the Pension Adjustment Factor. In both cases, the consolidation will meet the no-net-harm standard because the consolidations will not increase the total amount paid by customers. In fact, there is some potential for customer savings resulting from the large procurements for Basic Service, and the simplification of having uniform rate levels throughout NSTAR Electric will avoid customer confusion and streamline the regulatory review and approval processes in the future.

In summary, this merger formally implements a business structure that mirrors the operational reality that the Companies are functioning as a single entity. Practical and legal impediments no longer require the legal separation of the Companies, and the elimination of the outdated corporate structure is consistent with Department policy. The Companies have demonstrated that the proposal meets the statutory public-interest standard since there are no customer costs associated with the merger, and quantified and

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[1] The methodology for that transfer was not included in the Settlement Agreement, and the Companies have proposed for approval in this proceeding a revenue-neutral transfer so that neither the Companies nor customers benefit or are harmed by the transfer. Although the Companies agreed to reclassify the 13.8 kV facilities from transmission to distribution, they cannot do so without appropriate rate recovery in distribution rates (since the costs will no longer be recovered in transmission rates). It is for this reason that the Settlement Agreement expressly provided for the transfer of rate recovery.

[2] The Companies have proposed for approval in this case the uniform, expense-neutral depreciation rates that will be applied upon consummation of the merger.

qualitative benefits go well beyond the requirement that customers "would be at least as well served by approval of a proposal as by its denial". Boston Edison/Commonwealth Energy System Merger, D.T.E. 99-19, at 10 (1999). As described in this Initial Brief, based on this record, the Department should approve the proposed merger.

COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

Boston Edison Company, Cambridge Electric Light Company, Canal Electric Company and Commonwealth Electric Company d/b/a NSTAR Electric	)	D.T.E. 06-40

INITIAL BRIEF OF BOSTON EDISON COMPANY, CAMBRIDGE ELECTRIC LIGHT COMPANY, CANAL ELECTRIC COMPANY AND COMMONWEALTH ELECTRIC COMPANY

I. INTRODUCTION

On May 26, 2006, Boston Edison Company ("Boston Edison"), Cambridge Electric Light Company ("Cambridge"), Canal Electric Company ("Canal") and Commonwealth Electric Company ("Commonwealth"; together, the "Companies") filed a petition requesting approval from the Department of Telecommunications and Energy (the "Department"), pursuant to G.L. c. 164, § 96, of the proposed merger among and between the Companies to create a single electric company, NSTAR Electric Company ("NSTAR Electric"). The Department docketed the Companies' filing as D.T.E. 06-40.

On June 12, 2006, the Department issued a Notice of Public Hearing and Procedural Conference that established a deadline of June 26, 2006, for petitions for leave to intervene in these proceedings (the "Notice"). The Notice referenced that the Companies' Petition is a continuation of a multi-year plan to merge the Companies into a single corporate entity pursuant to NSTAR Rate Settlement, D.T.E. 05-85 (2005); Boston Edison Company/Commonwealth Energy System Merger, D.T.E. 99-19 (1999); Attorney General v. Department of Telecommunications and Energy, 438 Mass. 256 (2002). Notice at 1.

The Attorney General of Massachusetts (the "Attorney General") filed a Notice of Appearance of Counsel and a Notice of Intervention on June 21, 2006 pursuant to G.L. c. 12, § 11E. In addition, the following entities submitted timely petitions for full-party status in this proceeding: (1) The Energy Consortium ("TEC"); (2) Cape Light Compact ("CLC"); (3) the Retail Energy Supply Association ("RESA"); (4) Northeast Energy Associates ("NEA"); (5) President and Fellows of Harvard College ("Harvard"); and (6) Massachusetts Institute of Technology ("MIT"). In addition, Direct Energy Services, LLC ("Direct Energy") submitted a petition for limited-participant status. The Companies filed an opposition to the petitions of RESA and NEA on June 28, 2006. At the procedural conference held on June 29, 2006, the Hearing Officer granted the petitions of CLC, TEC, MIT, Harvard, RESA and Direct Energy. The Hearing Officer denied NEA's motion for intervention, instead granting NEA limited-participant status (Tr. [June 29, 2006] at 9-13).

During the discovery phase of the proceeding, the Department issued six sets of information requests, the Attorney General issued five sets of information requests, MIT issued two sets of information requests, and CLC and RESA each issued one set of information requests. Four days of evidentiary hearings were held between August 14, 2006 and August 23, 2006. In total, the evidentiary record in this case is comprehensive and includes approximately 269 exhibits (responses to 221 information requests and 28 record requests, as well as 18 exhibits presented at hearing, including the initial filing) and 584 transcript pages.

II. DESCRIPTION OF MERGER PROPOSAL

The transaction proposed by the Companies will consist of a merger under Massachusetts law, whereby each of Cambridge, Commonwealth and Canal will combine with and into Boston Edison (Exh. NSTAR-CLV-1, at 3-4). As the sole surviving corporate entity, Boston Edison will change its corporate name to NSTAR Electric Company, either upon the consummation of the transaction or thereafter (id. at 4). As a result of the merger, and by operation of the law, the facilities, properties and other rights, assets, franchises and liabilities will vest in Boston Edison (id.). The debt of Cambridge and Commonwealth will be retired (Exh. DTE-1-3; Exh. DTE-1-4). NSTAR Electric will cancel its common equity shares in Cambridge, Commonwealth and Canal and those three companies will cease to exist (Exh. NSTAR-CLV-1, at 3-4). The exchange ratios were computed based on the relative total common equity of each of the Companies as of December 31, 2005 per the Securities and Exchange Commission reports (Exh. DTE-1-2, Att. DTE-1-2).

The Companies intend to recall the debt for Cambridge and Commonwealth, instead of assuming this debt, because in the event that the merged Boston Edison were to assume the Cambridge and Commonwealth debt, it would also become subject to the covenants and restrictions contained in the indentures and loan agreements applicable to those debt obligations (Exh. DTE-1-7 (corrected)). These covenants and restrictions, after the merger, would apply to the entire operations of the combined company, including Boston Edison's operations if the debt were to be assumed (id.). Unlike Boston Edison, neither Cambridge nor Commonwealth accessed the public debt markets (id.). As a result, the covenants and restrictions applicable to the Cambridge and Commonwealth debt are more restrictive than the covenants and restrictions applicable to the Boston Edison debt obligations (id.; Exh. DTE-1-3, Att. DTE-1-3(b)-(e); Tr. 1, at 19). Differing levels of covenants and restrictions creates issues for the newly formed company (Exh. DTE-1-7 (corrected); Tr. 1, at 19). If the merged company were required to comply with the more restrictive covenants, it would limit its flexibility because the combined company might not be able to comply with many of the covenants and restrictions (Exh. DTE-1-7 (corrected); Tr. 1, at 19). Recalling the debt eliminates these issues (Exh. DTE-1-7 (corrected); Tr. 1, at 19). The combined entity will have the same access to the public debt markets that Boston Edison currently has and so will be able to borrow upon more favorable terms than Cambridge and Commonwealth (Exh. DTE-1-7 (corrected); Tr. 1, at 19).[3] In addition, customers will benefit from the retirement of existing debt by locking in lower rates for the future (Tr. 1, at 23; Exh. DTE-1-6).

The proposed merger will require approval from the Department as well as from the Federal Energy Regulatory Commission ("FERC") (Exh. NSTAR-CLV-1, at 4; Exh. NSTAR-CLV-3; Exh. DTE-1-12). The Companies will not need to amend their transmission service agreements under their open access transmission tariffs ("OATTs") in anticipation of or following the consummation of the merger (Exh. AG-2-7). Under Massachusetts law, Cambridge's and Commonwealth's transmission service agreements will be automatically assumed by Boston Edison (id.). No FERC filing is required for any transmission service agreements that conform to the form of service agreement provided under the Companies' *pro forma* OATTs. For those transmission service

[3] Boston Edison issued $200 million of 30-year debentures in anticipation of financing the recall of the long-term debt of Cambridge and Commonwealth as part of this merger (Exh. NSTAR-CLV-1, at 11; Exh. DTE-1-6). Accordingly, for ratemaking purposes, the Companies are proposing, as part of the merger approval by the Department, for authority to amortize the call premiums over the remaining life of that 30-year debt issuance (id.).

agreements that are either not conforming to the Companies' OATTs in some manner, or that are bilateral transmission service agreements not subject to the terms of a tariff, the Companies anticipate filing at FERC a notice of successions of each of those contracts from either Cambridge or Commonwealth to Boston Edison (id.). Such notices of succession will be filed within 30 days of the assumption of such agreements by Boston Edison (id.).

According to the Settlement Agreement approved by the Department in D.T.E. 05-85, rate-design changes proposed in this merger are limited. The Settlement Agreement contemplates that NSTAR Electric Company will be established by the merging Companies by January 2, 2007 (Settlement Agreement at ¶ 2.16) (Exh. NSTAR-CLV-1, at 9). Under the terms of the Settlement Agreement, the merged NSTAR Electric will maintain separate distribution rates and transition charges for customers in the existing service territories of Boston Edison, Cambridge and Commonwealth until at least January 1, 2010 (Settlement Agreement at ¶ 2.17) (id.).[4] The Settlement Agreement permits and governs the consolidation of transmission rates and the ratemaking treatment of Cambridge's 13.8 kilovolt ("kV") facilities (Settlement Agreement at ¶ 2.18) (id.). In addition, the Companies propose to consolidate the rates for Basic Service and for the Pension Adjustment Factor (Exh. NSTAR-CLV-1, at 12-16).

Because G.L. c. 164, § 21 ("Section 21") limits the transfer of utility franchises, it is appropriate and necessary for the Department, in approving the merger, to confirm and to ratify that all of the franchise rights and obligations currently held by Cambridge and

[4] Indeed, the Companies are not proposing to consolidate distribution rates or to change transition rates (Exh. CLC-1-10; Exh. CLC-1-11; Exh. CLC-1-12; Exh. CLC-13; Tr. 2, at 246).

Commonwealth continue with Boston Edison (as renamed NSTAR Electric Company) after the consummation of the merger. Section 21 states: "A corporation subject to this chapter shall not, except as otherwise expressly provided, transfer its franchise, lease its works or contract with any person, association or corporation to carry on its works, without the authority of the general court." The Department has previously found that approval of a merger pursuant to G.L. c. 164, § 96 ("Section 96") obviates the need for legislative approval under Section 21 because Section 96 "expressly provide[s]" the Department with authority to review and approved mergers of subject corporations. Eastern Enterprises and Colonial Gas Company, D.T.E. 98-128, at 104 (1999); Eastern Enterprises and Essex County Gas Company, D.T.E. 98-27, at 75 (1998); Haverhill Gas Company, D.P.U. 1301, at 4-5 (1984). Accordingly, the Companies have requested that the Department confirm that NSTAR Electric, as the surviving corporation of the merger, will retain all the franchise rights and obligations that were previously held by Boston Edison, Cambridge and Commonwealth and that further action, pursuant to G.L. c. 164, § 21, is not required to consummate the merger.

In approving the merger under Section 96, it is appropriate for the Department to confirm and to ratify that all of the franchise rights and obligations currently held by Cambridge and Commonwealth continue with Boston Edison and thereafter with NSTAR Electric upon the consummation of the merger (Exh. DTE-1-8). Among those rights and obligations are: (1) the exclusive rights and obligations of NSTAR Electric to provide distribution service within the former Companies' service territories as set forth in the Restructuring Act at G.L. c. 164, § 1B(a); (2) the rights and obligations to maintain the physical infrastructure necessary to exercise its transmission and distribution franchise, including, without limitation, (a) rights at railroad crossings to ensure continuity of service along and across these areas (see G.L. c. 164, § 73); (b) grants of locations in public ways; and (c) crossings of quasi-public lands (including property held by the Massachusetts Bay Transportation Authority, the Massachusetts Water Resources Authority, the Massachusetts Port Authority, the Massachusetts Turnpike Authority, the Department of Conservation and Recreation, etc.) (see G.L. c. 166, § 22); (3) rights and obligations obtained pursuant to NSTAR Electric's authority under G.L. c. 164, § 71 to construct transmission lines; (4) NSTAR Electric's ability to petition the Department under G.L. c. 164, § 72 for authority to construct transmission and distribution facilities; and (5) any and all other rights and responsibilities afforded to NSTAR Electric as a "distribution company" under Chapter 164 and any and all other applicable General Laws with regard to the transmission and distribution of electricity within the Commonwealth (id.).

III. STANDARD OF REVIEW

The Department's authority to review and approve mergers and acquisitions is found at G.L. c. 164, § 96, which requires the Department to find that mergers and acquisitions are "consistent with the public interest" as a condition for approval. Eastern-Colonial Acquisition, D.T.E. 98-128, at 4-5 (1999); Eastern-Essex Acquisition, D.T.E. 98-27, at 7-8 (1998). In prior cases, the Department has construed the Section 96 standard of consistency with the public interest as requiring a balancing of the costs and benefits attendant on any proposed merger or acquisition. Eastern-Colonial Acquisition, D.T.E. 98-128, at 5; Eastern-Essex Acquisition, D.T.E. 98-27, at 8. The Department has stated that the core of the consistency standard is "avoidance of harm to the public."

Eastern-Colonial Acquisition, D.T.E. 98-128, at 5; Eastern-Essex Acquisition, D.T.E. 98-27, at 7-8; Boston Edison Company, D.P.U. 850, at 5 (1983). Therefore, a proposed merger or acquisition is allowed to go forward upon a finding by the Department that the public interest would be at least as well served by approval of a proposal as by its denial. Eastern-Colonial Acquisition, D.T.E. 98-128, at 5; Eastern-Essex Acquisition, D.T.E. 98-27, at 8.

In Mergers and Acquisitions, the Department reaffirmed that it would consider the potential gains and losses of a proposed merger to determine whether the proposed transaction satisfies the Section 96 standard. D.P.U. 93-167-A at 6, 7, 9 (1994); Boston Edison Company, D.P.U. 97-63, at 7 (1998). The public-interest standard, in accordance with Department precedent, must be understood as a "no net harm," rather than a "net benefit" test. Eastern-Colonial Acquisition, D.T.E. 98-128, at 5; Eastern-Essex Acquisition, D.T.E. 98-27, at 8. The Department considers the special factors of an individual proposal to determine whether it is consistent with the public interest. Eastern-Essex Acquisition, D.T.E. 98-27, at 8; Boston Edison Company, D.P.U. 97-63, at 7; Mergers and Acquisitions, D.P.U. 93-167-A at 7-9. To meet this standard, costs or disadvantages of a proposed merger must be accompanied by offsetting benefits that warrant their allowance. Eastern-Essex Acquisition, D.T.E. 98-27, at 8; Boston Edison Company, D.P.U. 97-63, at 7; Mergers and Acquisitions, D.P.U. 93-167-A at 18-19.

Various factors may be considered in determining whether a proposed merger or acquisition is consistent with the public interest pursuant to Section 96. Eastern-Essex Acquisition, D.T.E. 98-27, at 8. These factors were set forth in Mergers and Acquisitions: (1) effect on rates; (2) effect on the quality of service; (3) resulting net savings; (4) effect on competition; (5) financial integrity of the post-merger entity; (6) fairness of the distribution of resulting benefits between shareholders and ratepayers; (7) societal costs, such as job loss; (8) effect on economic development; and (9) alternatives to the merger or acquisition. D.P.U. 93-167-A at 7-9; Eastern-Colonial Acquisition, D.T.E. 98-128, at 6; Eastern-Essex Acquisition, D.T.E. 98-27, at 8-9. This list is illustrative and not "exhaustive," and the Department may consider other factors when evaluating a Section 96 proposal. Eastern-Essex Acquisition, D.T.E. 98-27, at 9; Mergers and Acquisitions, D.P.U. 93-167-A at 9.

IV. THE PROPOSED MERGER MEETS THE STATUTORY "NO NET HARM" TEST.

As mentioned above, this merger is the final structural/corporate step in the merger that created NSTAR (Exh. NSTAR-CLV-1, at 9). The Department has already reviewed the major impacts of merging the companies; thus, for this intra-company consolidation of NSTAR Electric, the remaining impacts generally reviewed by the Department in merger cases are not material (id.). In fact, the vast majority of the costs and benefits of the NSTAR merger were considered by the Department in D.T.E. 99-19, in which the Department determined that the merger was in the public interest because it created significant customer benefits (well beyond the minimum "no net harm" standard) (D.T.E. 99-19, at 84) (id. at 9-10). In this merger of NSTAR Electric, there are no significant, net impacts on competition, economic development, societal costs and benefits, the allocation of benefits and costs between customers and shareholders, or service quality (id. at 10). Indeed, costs associated with this merger are minimal, including estimated legal costs of $350,000 and information technology costs of $250,000 to $300,000 (Exh. DTE-3-5). However, these costs would be borne by shareholders and would not be deferred for recovery at a future date (id.). Moreover, by combining the companies, there is expected to be some minor efficiency gains or strengthening of NSTAR Electric's financial integrity that can be achieved over time through the consolidation of accounting functions and financial instruments (Exh. NSTAR-CLV-1, at 10; Tr. 3, at 345-348). Although the bulk of the operational savings were already accomplished by combining the work force, there are small efficiency savings in reducing the number of separate accounts to be maintained, reconciling and auditing separate legal entities and reducing the number of regulatory filings for the individual companies, which will streamline regulatory oversight (id.; Exh. DTE-3-4; Tr. 3, at 345-346).

For example, in the future, the Department will have to review only two rate filings to cover the NSTAR electric and gas distribution companies rather than the four that were included in D.T.E. 05-85 (Exh. NSTAR-CLV-1, at 10; Tr. 3, at 345-346). Moreover, the consolidation would provide the opportunity for better customer service because customer representatives would no longer be required to track and understand regional tariff differences for the rates that are consolidated (Exh. DTE-3-4). Also, the name on customers' bills, "NSTAR," will eventually mate the name of the company providing their service, "NSTAR Electric," thereby reducing the potential for customer confusion (id.; Tr. 3, at 346). In addition, the consolidation would also allow for greater transparency for regulators because there would be fewer filings and easier review processes (Exh. DTE-3-4). Accordingly, the same considerations that led the Department to approve the earlier NSTAR merger in D.T.E. 99-19 support the implementation of this further step in this proceeding (Exh. NSTAR-CLV-1, at 10).

A. Consolidation of Rates

Under the terms of the Settlement Agreement at paragraph 2.17, NSTAR Electric is required to maintain separate distribution and transition rates for the three service territories through January 1, 2010 (Exh. NSTAR-CLV-1, at 11; Tr. 2, at 246-247). Thus, these rate elements will not be affected at this time by merging of the Companies (Exh. NSTAR-CLV-1, at 11). Any future proposal to consolidate distribution and/or transition rates after this date would require Department review and approval (id.). However, the consolidation of other rate elements is possible under the terms of the Settlement Agreement, and NSTAR Electric proposes to consolidate those rates beginning January 1, 2007, as a first step in the simplification of rates under a merged NSTAR Electric Company (id.; Exh. AG-2-8; Tr. 3, at 412-413).

NSTAR Electric proposes to consolidate retail rates for Default ("Basic") Service, the Pension Adjustment Factor and retail Transmission Service (Exh. NSTAR-CLV-1, at 12; Exh. AG-5-7; Exh. DTE-1-13). The consolidation of the Basic Service adders, in conjunction with the consolidation of the Basic Service rates, will produce a single average Basic Service adder applicable to all rate classes in the merged company (Exh. DTE-1-13; Exh. DTE-4-5; Exh. DTE-5-11).[5] The overall consolidation of Basic Service rates will help the Department, the Attorney General and NSTAR Electric minimize the

[5] The Companies are not proposing to change the distribution rates in each company as a result of the consolidation of the Basic Service adder (Exh. DTE-1-13; Exh. DTE-4-7). Such distribution rates have been set in accordance with the Companies' 2005 Settlement Agreement approved in D.T.E. 05-85, and the Basic Service credits included in these distribution rates reflect the Settlement test-year level of Basic Service procurement costs and, as such, are fixed and not generally subject to change outside of a rate case proceeding (Exh. DTE-1-13; Exh. DTE-4-7). Conversely, the Basic Service adder will change each year in proportion to changes in NSTAR Electric's annual bad-debt costs (Exh. DTE-1-13; Exh. DTE-4-7; Exh. DTE-4-8). Consequently, there is no matching of the recovery under the Basic Service adder with credits to the distribution rates for periods after the Settlement test year (Exh. DTE-1-13).

administrative burden of maintaining separate schedules, analyses and filings for what is essentially one operating company (Exh. NSTAR-CLV-1, at 12). In addition, it will be simpler for customers to understand rates and rate changes by providing single unified rates (id.). Because the aggregate level of rates will be no higher than if separate rates (and separate corporate entities) were maintained for Boston Edison, Cambridge and Commonwealth, there is no net harm overall from the consolidation (id.). The Companies have provided bill-impact calculations in Exhibit DTE-3-7, Attachments DTE-3-7(a) through DTE-3-7(c). These calculations attempt to isolate the difference between current prices and post-merger prices for the transmission, pension adjustment and default service adder rate components (Exh. DTE-3-7). And, for Cambridge, these bill impacts reflect the proposed ratemaking treatment for the transfer of the 13.8 kV facilities from transmission to distribution rate components (id.).

NSTAR Electric's process of obtaining supplies for Basic Service will change only to the extent that there will be solicitations for one company rather than for three. Solicitations will be performed in accordance with the Department's directives, as modified by the Settlement Agreement for residential customers (Settlement Agreement [D.T.E. 05-85] at ¶ 2.21) (Exh. NSTAR-CLV-1, at 12). After the issuance of a request for proposals, the Basic Service contracts are awarded to the winning bidder(s) from the competitive market with the lowest price in each load zone and customer class (Exh. NSTAR-CLV-1, at 12). This will not change. The only difference is that the suppliers will contract with NSTAR Electric instead of the separate companies (id.).

In accordance with Department requirements, supplies for Basic Service are procured on a rate class and load-zone basis (Exh. NSTAR-CLV-1, at 13). The

Cambridge service territory is located entirely in the Northeast Massachusetts load zone ("NEMA"), the Commonwealth service territory is located entirely in the Southeast Massachusetts load zone ("SEMA") and Boston Edison's service territory is located predominately within NEMA and partially in SEMA (id.). In setting retail Basic Service rates for Boston Edison, separate NEMA and SEMA rates are offered to large commercial and industrial customers, but a blended rate is offered to residential and small commercial customers (id.). After the merger, NSTAR Electric will operate in the two zones (NEMA and SEMA), just as Boston Edison does, and the consolidated entity will follow the same Department-mandated rate procedures currently in effect for Boston Edison (id.). That is, large commercial and industrial customers will receive separate NEMA or SEMA rates, based on the customer's location (id.). So these customers would not see any change with the merger (id.). Residential and small commercial customers throughout the merged NSTAR Electric service territory will receive blended rates in accordance with Department policies (id.; Exh. RESA-1-3). See also D.T.E. 02-40-A at 11 (2003).

These changes will not affect the rates paid by residential and small commercial customers in the aggregate, but there may be some small difference between the blended NEMA and SEMA rate and the individual component rates (Exh. NSTAR-CLV-1, at 13; Exh. DTE-1-23; Tr. 3, at 310-312). The difference in the costs between the NEMA and SEMA load zones is not significant and, with the new 345 kV transmission upgrades to be completed by Boston Edison, this differential is expected to be minimal and declining in the future (Exh. NSTAR-CLV-1, at 13-14).[6] An analysis of the real-time locational marginal pricing on a monthly, load-weighted basis was performed for the historical calendar years 2004 and 2005 for the NEMA and SEMA regions and is shown in Exhibit NSTAR-CLV-4 (id. at 14). On an average, 12-monthly-load-weighted basis, NEMA's prices were higher than the SEMA's prices by only 1.5 percent and 3.7 percent, for the years 2004 and 2005, respectively (id.). A key reason for the differential is the existence of transmission constraints in the NEMA region (id.). This differential in pricing of power supplies between the two regions should decline considerably when Boston Edison's new 345 kV line between Stoughton and Boston is placed in service (id.). Indeed, the new 345 kV line will substantially increase the transmission capacity of the integrated network system in the NEMA zone, including the Greater Boston area, thereby reducing the transmission congestion constraints of importing power into NEMA (id.).

B. Pension Adjustment Factor

Although there are separate pension adjustment factors ("PAF") for the three companies, the underlying pension and post-retirement benefits are corporate-wide expenses that are allocated to the companies in the annual PAF filing (Exh. NSTAR-CLV-1, at 14-15). The PAF will be determined annually for the merged NSTAR Electric beginning in the year 2007 (Exh. CLC-1-30). The cost of capital and carrying charge are identical for all Companies and there are no company-specific pension benefits (id.). After the merger of NSTAR Electric, there would be no reason to continue to allocate

[6] Costs associated with the 345 kV transmission line are irrelevant to the proposed merger (Exh. MIT-1-6; Tr. 1, at 69-72). These issues will be reviewed in a separate proceeding in the future, and, therefore, a premature review of these costs during this proceeding is improper (Exh. MIT-1-6; Tr. 1, at 69-72).

costs among customers of the former three electric companies, and the only allocation would be between NSTAR Electric and NSTAR Gas (Exh. NSTAR-CLV-1, at 15; Exh. CLC-1-30). Indeed, the merger will allow for simplification of the pension filing (Exh. CLC-1-30).

Moreover, consolidation of the PAF would not, in the aggregate, have an impact on rates overall (Exh. NSTAR-CLV-1, at 15). However, there would be a small impact on the individual rates for customers of the three operating companies (id.; Exh. CLC-1-30, Att. CLC-1-30(a), Att. CLC-1-30(b), Att. CLC-1-30(c)). For example, in 2006, the PAF for Boston Edison is $0.00030 per kilowatt-hour ("kWh"), for Cambridge is $0.00086 per kWh and for Commonwealth is $0.00080 per kWh (Exh. NSTAR-CLV-1, at 15). If a single PAF were established for a merged NSTAR Electric in 2006, the PAF would have been $0.00045 per kWh (id.). Thus, the PAFs for Cambridge and Commonwealth customers would have been slightly lower and the PAF for Boston Edison would have been slightly higher (id.). The increase in the average residential, non-heating bill for Boston Edison customers would have been less than 8 cents per month, or less than 0.1 percent (id.). In addition, the consolidation of the PAF will have benefits by creating one unified rate, thereby leading to the easier understanding of the rates and easier communications with customers (id.).

C. Transmission Costs

The transmission costs incurred by each company reflect the transmission investment costs and expenses that are assessed under the various FERC rates and tariffs (Exh. NSTAR-CLV-1, at 16). The FERC-jurisdictional rates and tariffs consist of regional as well as localized costs, and are a passthrough to retail customers on a load basis (id.). The regional costs are composed of: (1) Regional Network Service costs;

(2) Scheduling and Dispatch costs; (3) Congestion Management costs; (4) System Restoration and Planning costs; (5) REMVEC costs; (6) VAR support; and (7) NEPOOL administration costs (id.). The local costs consist of: (1) Local Network Service costs and (2) Local Scheduling and Dispatch costs (id.). When the Companies consolidate into Boston Edison, Boston Edison's existing local FERC transmission tariff will be the surviving FERC-approved transmission tariff on file at FERC and effective under the provisions of the Federal Power Act (id.; Exh. AG-4-6). NSTAR Electric is thus required to follow the terms of the Boston Edison tariff after completion of the merger (Exh. AG-4-6). NSTAR Electric currently anticipates making a FERC Section 205 filing to revise the existing Boston Edison tariff in a way that will build on the settlement principles currently being discussed for Cambridge and Commonwealth in FERC Docket No. ER05-742-000 (id.; Tr. 1, at 54-55). Since the existing FERC local transmission tariffs are formula rates with very similar provisions, once the assets and expenses are consolidated, the cost impact of implementing Boston Edison's transmission tariff for NSTAR Electric will be minimal (Exh. NSTAR-CLV-1, at 16).[7]

With respect to the Regional Network Service ("RNS") costs that ISO-NE bills to the Companies under the ISO-NE Tariff, there will be minimal cost impacts once the assets and expenses have been combined (Exh. NSTAR-CLV-1, at 17). There is only one RNS formula rate under the ISO-NE Tariff that is applicable to all users of Pool Transmission Facilities ("PTF") (id.). As such, NSTAR Electric's RNS revenue requirement associated with providing service over PTF facilities will be calculated on

7 As discussed in more detail below, Cambridge's transmission tariff includes 13.8 kV facilities, which will require a reclassification of those facilities and an adjustment in the recovery of the corresponding costs (Exh. NSTAR-CLV-1, at 17).

the same basis as that which was done on an individual-company basis (id.). As for the other regional costs, there would be very minimal regional cost shifting resulting from the consolidation, since the other regional costs, except for congestion management, are currently socialized among all the transmission providers on a network load basis (id.).

Moreover, the congestion management costs that are recovered through transmission rates are attributed to Reliability Must Run ("RMR") and Special Constraint Resource ("SCR") costs (Exh. NSTAR-CLV-1, at 17; Exh. DTE-1-15; Exh. MIT-1-13; Exh. AG-3-2), the level of which have been highly variable and impossible to predict with certainty (Exh. NSTAR-CLV-1, at 18, Exh. CLC-1-9). The RMR costs are for agreements between the ISO-NE and the owners of generating units that are required to run for area reliability, but have successfully demonstrated to the ISO-NE and FERC that they would not be dispatched economically within the existing market structure (Exh. DTE-1-15). The RMR costs within the New England Control Area are determined for each of the various established load zones and then socialized within each load zone on a network load basis to all the companies within the load zone (Exh. NSTAR-CLV-1, at 18; Exh. MIT-1-13). These costs are supported by the transmission customers within the load zone (i.e., NEMA and SEMA) in which the unit is located (Exh. DTE-1-15). The transmission rates for each customer class are adjusted each year by applying the ratio of the proposed average company transmission rate calculated for the given year to the actual average company transmission rate (id.). Note that the transmission rates for each customer class were initially established when the Companies unbundled their consolidated service rates for the retail access date (id.). Thus, the transmission RMR costs are allocated by customer class in the same proportion as all the other transmission costs developed in the transmission reconciliation filing (id.).

SCR is any generating resource called upon to run out-of-merit for any reliability purpose to provide relief for a constraint (thermal, voltage or stability) not reflected in ISO-NE's models for operating the NEPOOL Transmission System (Exh. DTE-1-15). The SCR costs are charged specifically to the company that requires the SCR for local reliability purposes (Exh. NSTAR-CLV-1, at 18; Exh. DTE-1-15). On a daily basis, the company requesting the generation resource employs its system operators to assess the system based upon the expected loads and known system conditions to determine whether generation is required to maintain adequate voltage levels or to protect against a potential outage of a transmission element (Exh. DTE-1-15). If the generation is deemed to be needed to maintain reliability, the SCR costs assessed by ISO-NE are then passed through to retail customers in accordance with each of the Companies' respective retail tariffs (id.). Like RMR costs, the transmission SCR costs are allocated by customer class in the same proportion as all the other transmission costs developed in the transmission reconciliation filing (id.).

It is difficult to ascertain if there are any negative cost impacts going forward because of the uncertainty as to the life expectancy of the RMR agreements that are in effect today and as to whether any new RMRs will be filed and approved in the future (Exh. NSTAR-CLV-1, at 18; Exh. CLC-1-9). Many of the RMR agreements have termination provisions that will be exercised once an installed capacity mechanism is recognized as fully implemented (id.). It is unclear at this juncture when that new market will begin, but once it does, the majority of the RMR costs that are being charged today as congestion costs are expected to cease (id.). As for SCR costs, while each company incurs these charges at various times, Cambridge has incurred the majority of the SCR costs, based upon the use of the Mirant Kendall Generating Station (id.). When load is completely transferred to the new East Cambridge Substation in Cambridge, Cambridge will no longer be reliant on this internal generation for providing local system support (id.). Because of the uncertainty of the future amount of congestion costs that will be recoverable under transmission rates, congestion management costs cannot be used as a long-term factor in establishing cost effects in merging the transmission costs of all three companies into NSTAR Electric (id.).

Once the Companies merge into a single NSTAR Electric, the Companies will operate over the NEMA and SEMA load zones and will socialize the effects of congestion costs billed by ISO-NE across the two zones (id.). This would be accomplished by consolidating the effects of different congestion costs over two load zones and charging customers the average costs of congestion (id.). This is the present practice of Boston Edison and is also being followed by National Grid for its customers (id.).

Forecasting the effect of consolidating the retail transmission rates for all three companies is complex (Exh. NSTAR-CLV-1, at 19; Exh. NSTAR-CLV-5(Revised)). The retail transmission costs shown in Exhibit NSTAR-CLV-5(Revised) reflect actual 2005 costs and were adjusted to exclude congestion costs and the over/under collection costs from the previous year since those are a one-time occurrence and reconciliation (Exh. NSTAR-CLV-1, at 19). The consolidated local network service ("LNS") revenue requirements were calculated according to the surviving Boston Edison LNS tariff, with adjustments to existing data, where necessary, to reflect a combined company (id.). Most significant of these adjustments are: (1) the effect of adopting Boston Edison transmission depreciation rates for assets originally owned by Cambridge and Commonwealth, thus reducing depreciation expense to be recovered; (2) eliminating inter-company support expenses and revenues; (3) reclassifying costs among FERC accounts reflecting consistent accounting practices once the Companies are combined; and (4) adopting an assumed capital structure for the combined companies of 55 percent common equity rather than the approximate 62 percent common equity that would result if the current capital structures were simply added together (id. at 19-20). Cambridge's transmission costs also exclude the 13.8 kV-related costs to account for the transfer of the recovery of those costs in distribution rates (id. at 19-20). As illustrated by Exhibit NSTAR-CLV-5 (Revised), consolidation could result in a net reduction in total transmission rates to customers (id. at 20). There is a slight increase of 0.8 percent for transmission customers of Commonwealth, and customers of Boston Edison and Cambridge would see a reduction of 2.9 percent and 21.0 percent, respectively, in the transmission portion of their bill (based on 2005 costs and the elimination of congestion charges) (id.).

D. Reclassification of Cambridge's 13.8 kV Facilities

As part of the merger, and in accordance with the terms of the Department-approved Settlement Agreement in D.T.E. 05-85 (¶ 2.18), NSTAR Electric will reclassify Cambridge's 13.8 kV facilities from transmission to distribution (Exh. NSTAR-CLV-1, at 20; Exh. DTE-1-19; Exh. DTE-4-4). Costs relating to Cambridge's 13.8 kV facilities are currently included in transmission rates rather than in distribution rates (Exh. NSTAR-CLV-1, at 20). This is unusual and reflects the operational characteristics of

Cambridge's system that existed a decade ago (id.). Since that time, additions to Cambridge's system, specifically the addition of 115 kV lines and a new substation, combined with the resulting changes in operational practices of the 13.8 kV system, have changed the dynamics of the system (id. at 20-21; Exh. DTE-2-8; Exh. AG-4-3). The 13.8 kV facilities changed from an integrated 13.8 kV transmission network to a distribution system that provides power to local load (Exh. NSTAR-CLV-1, at 21). The Department-approved Settlement Agreement provides that, upon the consummation of the merger of NSTAR Electric, "Cambridge's 13.8 kV facilities shall be reclassified as distribution facilities and recovered in distribution rates…" (Settlement Agreement at ¶ 2.18) (id.).

1. FERC Classification

Cambridge's 13.8 kV system was originally classified as transmission facilities because those facilities interconnected generation sources and provided an efficient means of delivering the power to local load centers (Exh. NSTAR-CLV-1, at 21). In 1997, when Cambridge last obtained approval for classifying its 13.8 kV system as transmission (D.P.U./D.T.E. 97-93), the Kendall Generating Station located in Cambridge had interconnection ties via 13.8 kV circuits through Cambridge's major substations that also connected to Boston Edison's tie-line facilities (id.). This assured that generation could flow to major load centers in the City of Cambridge, even if there was not enough external power flowing over Boston Edison's bulk tie-line facilities into Cambridge's territory (id.). Thus, Cambridge's 13.8 kV system of substations and circuits was integral in providing the transmission of power to its local load centers at that time (id.).

However, with the recent completion of the East Cambridge Substation, and the planned second 115 kV transmission line interconnection from the East Cambridge Substation to Putnam Substation, Cambridge will no longer be reliant on the Kendall Generation Station for servicing any of the load requirements of its customers. As such, facility changes are occurring where the Kendall Generating Station is now interconnected to the Cambridge system through a 115 kV line to the new East Cambridge Substation and will be connected to a second 115 kV line to its Putnam Substation (id. at 21-22; Exh. AG-5-4; Tr. 1, at 14-15). Power will be transmitted to Cambridge's system and to the New England grid through Cambridge's 115 kV lines and interconnecting substation switching facilities, instead of through Cambridge's 13.8 kV lines and 13.8 kV substations (id.). Thus, the function of the 13.8 kV system has shifted from a transmission system to a more typical distribution system, where its function is to supply power to local distribution customers (id.).

FERC has established a seven-part, standard test to establish the functional category of transmission and distribution facilities to determine if a facility performs a distribution function (Exh. NSTAR-CLV-1, at 22). See FERC Order 888 at 31,770-31,771. As a result of the evolution of Cambridge's transmission and distribution system over the past decade, its 13.8 kV facilities meet the standard to be classified as distribution facilities (Exh. NSTAR-CLV-1, at 23). The below table compares the application of the FERC seven-part test with regard to Cambridge's 13.8 kV facilities as serving a distribution function in 1997 and after the merger in 2007:

Test of 13.8 kV Facilities	1997	2007
1. Distribution in close proximity to retail customers	No	Yes
2. Distribution radial in character	No	Yes
3. Power flows in, rarely out	No	Yes
4. Power is used not just transported to other market	No	Yes
5. Power is consumed in the area	No	Yes
6. Meters are based at the interface	Yes	Yes
7. Low voltage levels	Yes	Yes

(Exh. NSTAR-CLV-1, at 23; Exh. AG-5-9 (**CONFIDENTIAL ATTACHMENTS**)). In the case of Cambridge, in 1997 in D.P.U./D.T.E. 97-93 when the test was applied, the operating characteristics of the 13.8 kV system did not meet the criteria for categorizing the 13.8 kV facilities as distribution (except for its low-voltage designation and the location of its meters) (id.). In fact, at that time, the 13.8 kV system was an integrated transmission system that provided a reliable interchange of power from multiple supply points (internal generation and interconnections with the New England bulk transmission system) to distribution substations (id.).

In 2007, the 13.8 kV system will no longer provide the numerous power paths that interconnect the generation facilities with Cambridge's internal bulk stations and other utilities bulk substations to supply the local distribution customers (Exh. NSTAR-CLV-1, at 24). With the addition of the new East Cambridge Bulk Substation, the network interconnecting capability of the 13.8 kV facilities can be displaced (id.). Internal generation will be interconnected to circuits at the 115 kV level and provides the power flow to the bulk substations and to the New England grid (id.). The 13.8 kV system on the other hand will become localized and provides radial links from the substations to customers' load (id.). When power flows into the 13.8 kV system, it will be used to serve the end-use customers in the area and will not be transported into another market (id. at 24-25). Presently, only one of the two 115 kV lines that will interconnect the East Cambridge Bulk Substation with the Putnam Substation has been completed (Tr. 1, at 137). Nonetheless, even with the single 115 kV line in place, the operational nature of the 13.8 kV facilities would be changed to distribution (id. at 153-157). As such, these factors support the conclusion that the 13.8 kV facilities now meet the criteria of FERC's seven-part test for reclassification as distribution facilities.

2. Transfer of Ratemaking to Distribution Rates

Although the Companies agreed to reclassify Cambridge's 13.8 kV facilities from transmission to distribution, they cannot do so without appropriate rate recovery in distribution rates (since the costs will no longer be recovered in transmission rates). It is for this reason that the terms of the Department-approved Settlement Agreement expressly provided that the collection of these costs from customers is to be transferred from transmission rates to distribution rates (Exh. NSTAR-CLV-1, at 25). The precise methodology for the rate transfer was not included in the Settlement Agreement, and NSTAR Electric proposes that this be accomplished through a revenue-neutral transfer of the revenue requirement that would have been collected in transmission rates to the distribution rates for Cambridge (id.; Exh. DTE-1-19). This will ensure that neither NSTAR Electric nor customers receives nor pays more than they otherwise would have (Exh. NSTAR-CLV-1, at 25). For example, the approximate revenue requirement associated with Cambridge's 13.8 kV facilities that is to be transferred from transmission to distribution service using the FERC-approved tariff rate formula is based upon 2005 data and will be based upon forecasted cost data for calendar year 2006, to be effective beginning January 2007 (id. at 25-26; Exh. NSTAR-CLV-7). NSTAR Electric will transfer that portion of the Cambridge transmission revenues attributed to the 13.8 kV facilities to its distribution rates (Exh. NSTAR-CLV-1, at 26). In addition, after the close of 2006, NSTAR Electric will determine the final costs and revenue requirement for the 13.8 kV facilities under the FERC-approved tariff, and an adjustment for the true-up amount will be made for customers in the Cambridge service territory in 2008 (id.). This reconciliation will be made in Cambridge's distribution and transmission rates (id.).

Under the terms of the Department-approved Settlement Agreement in D.T.E. 05-85, the reclassification of Cambridge's 13.8 kV facilities and corresponding transfer of rate recovery is contemplated to take place at the time of the merger (Exh. DTE-5-13). The change in classification must be done at year-end because the FERC tariffs are annual rates based on year-end plant balances and other data from the annual FERC Form 1 (id.). Changing classification at any other time makes revenue requirement determinations more complex and likely impossible to perform without a tariff change (id.). To ensure that this one-time adjustment affects only Cambridge's customers, the adjustment will be included directly in the distribution and transmission charges included in Cambridge's retail rate schedules (Exh. NSTAR-CLV-1, at 26; Exh. DTE-1-19). The reconciliation will ensure that there is neither an overcollection nor an undercollection

(Exh. NSTAR-CLV-1, at 26; Exh. DTE-1-19; Exh. DTE-1-22).[8]

The proposed method of transfer of the 13.8 kV revenue requirement will be revenue neutral for NSTAR Electric and for each of Cambridge's rate classes (Exh. NSTAR-CLV-1, at 28; see Exh. AG-4-1). This would be accomplished by first reducing current transmission prices for each retail rate class by the percentage decrease in total transmission revenue requirement resulting from the transfer (Exh. NSTAR-CLV-1, at 28). Next, distribution prices for each rate class will be increased by the corresponding decrease in transmission prices for each rate class (id.). Exhibit NSTAR-CLV-8 sets forth the transmission and distribution rate impacts to Cambridge's rate classes (id.). Overall, there would be no difference to rates for Cambridge customers when transmission and distribution are added together (id.). Once the regulatory approvals are in place for the merger of the transmission tariffs and the transfer of the 13.8 kV facilities to distribution, the retail transmission rates for 2007 will be consistent for all of NSTAR Electric's customers (id. at 29; Tr. 3, at 412-413).

E. Standby Rates

Cambridge currently has no customers that take service under its standby service rates, Rate SB-G2 and SB-G3 (RR-DTE-1; RR-DTE-3; RR-MIT-2; Exh. AG-2-13).

[8] The Department's statutory authority to establish rates, including NSTAR Electric's ratemaking proposal with regard to the transfer of Cambridge's 13.8 kV facilities, is set forth in G.L. c. 164, § 94, and the Department's general supervisory powers under G.L. c. 164, § 76 (Exh. MIT-2-11). G.L. c. 164, § 94 does not specify any particular ratemaking formula, and the Supreme Judicial Court has consistently determined that the Department has "broad authority to determine ratemaking matters in the public interest." Massachusetts Instit. of Tech. v. Department of Pub. Utils., 425 Mass. 856, 868 (1997) (citation omitted). Under this authority, the Department has approved reconciling mechanisms for a variety of different cost components including fuel charges, costs of gas adjustment clauses, local distribution adjustments clauses and residential adjustment clauses. See, e.g., Low-Income Discount Participation Rate, D.T.E. 01-106-C/D.T.E. 05-55/D.T.E. 05-56 (2005); Consumers Org. for Fair Energy Equality, Inc. v. Department of Pub. Utils., 368 Mass. 599 (1975).

Accordingly, there are no bill or revenue impacts associated with these rates (Exh. AG-2-13). However, in light of the proposed reclassification of 13.8 kV facilities, the contract demand price under the Companies' standby rates, Rate SB-G2 and Rate SB-G3, will increase (Tr. 2, at 169). The contract demand price refers to distribution prices under the standby service rate (id.). The distribution prices for supplemental service are revenue-neutral in that there is both a distribution charge and a transmission charge whose changes offset each other (id.). With regard to the contract demand price, a customer who has internal generation does not incur any transmission charges, so that there is not a transmission offset for the transmission charges relative to the contract demand (id.). In fact, such a customer pays no transmission charges for their internal generation until that customer draws power from the Cambridge system (id.).

As indicated during hearings, there is one customer with on-site generation that is subject to the rates set forth in Rate SB-G3, as in effect from time to time, pursuant to a Department-approved special contract (RR-DTE-1; RR-DTE-3; RR-MIT-2). Cambridge has successfully completed contract discussions with that customer in order to effect a contract amendment that ensures revenue neutrality for that customer from the proposed transfer of 13.8 kV facilities from transmission to distribution (RR-DTE-3(Supp)). Accordingly, all customers, including any customers subject to standby service rates, are being held harmless from the effect of the proposed merger. Thus, there is no need or benefit to phasing in the changes in the standby rate that would result from the 13.8 kV transfer (RR-DTE-1; RR-DTE-3; RR-MIT-2). A rate phase-in may be an appropriate measure where there are existing customers who may be adversely affected by a significant change in rates (id.). However, where (as here) there are no customers on the rate and no customers would experience an adverse rate impact, there is no basis for a rate phase-in, particularly for cost-based rates such as Cambridge's standby tariffs (id.). In effect, no net harm to customers is experienced by the proposal that might warrant a rate phase in (id.).

If required, the Companies would be amenable to delaying the implementation of the effect of the 13.8 kV transfer as it relates to Cambridge's standby rates for six months (i.e., until July 1, 2008) (RR-DTE-3). This would ensure that there is additional notice of the future rate change to customers who may be considering on-site generation and would delay the effect of the 13.8 kV transfer in the standby rate for an additional year (beyond when NSTAR Electric filed its proposal with the Department) for any customers that develop an on-site generating facility before June 30, 2007 (id.). In general terms, a similar approach was used in the settlement agreement entered into and approved by the Department in D.T.E. 03-121, wherein the structure in the standby rate did not become effective for approximately six months after it was proposed by the settling parties and approved by the Department in the standby rate proceeding (id.). The Companies believe that this approach would be a reasonable compromise as to the potential impact of the rate change in its standby tariffs (id.).

F. Consolidating Depreciation Rates

NSTAR Electric proposes to implement the terms of the Settlement Agreement relating to establishing uniform depreciation rates (Exh. NSTAR-CLV-1, at 29; Exh. DTE-2-3). After the completion of the merger, since there will be only one remaining corporate entity, only one set of accounting books will be maintained, which necessitates the establishment of consolidated depreciation rates to apply to the merged assets (id.; Exh. DTE-4-11). Paragraph 2.6.2 of the Settlement Agreement, as approved by the

Department, permits the merged NSTAR Electric to consolidate depreciation rates for Boston Edison, Cambridge and Commonwealth "that are expense neutral at the functional group level" (Exh. NSTAR-CLV-1, at 29; Exh. DTE-2-5; Exh. DTE-4-11). That is, the total depreciation expense for Boston Edison, Cambridge and Commonwealth using the rates currently in effect will result in the same total depreciation expense under the new combined rates within each functional plant category (Intangible, Distribution and General) (Exh. NSTAR-CLV-1, at 29).

There is no relation between the consolidation of depreciation rates and possible future proposals with regard to the redesign of retail distribution rates (Exh. DTE-4-11). Depreciation expense is an element of a company's revenue-requirement, which, under the terms of the Settlement Agreement approved by the Department in D.T.E. 05-85, is established in accordance with the SIP formula describe in paragraph 2.6 of the Settlement Agreement (id.). Any rate design/consolidation of distribution rates permitted to be proposed by the Companies by the Settlement Agreement at paragraph 2.12 will be unaffected by any expense-neutral consolidation of depreciation rates (id.).[9]

Under standard accounting practices, and unless otherwise ordered by the Department, all assets and accumulated depreciation would be transferred into the existing asset depreciation categories for Boston Edison and all assets would be depreciated using Boston Edison's depreciation rates (id.). This is why the Department-approved Settlement Agreement provides for the development of new uniform rates that

[9] The Companies are not proposing to consolidate distribution rates in this proceeding and approval of the merger would not necessitate the consolidation of distribution rates (Exh. CLC-1-10; Exh. CLC-1-11). Any rate consolidation proposal would be subject to Department review and approval in the future and would be governed by the terms of the Department-approved Settlement Agreement in D.T.E. 05-85 (Exh. CLC-1-10; Exh. CLC-1-11).

are expense neutral (id.). Absent establishing those new depreciation rates, the depreciation expense after the merger would be different from what it would have been had the Companies not merged, since Boston Edison's depreciation rates differ from those of the other companies (id.).[10] Furthermore, Boston Edison's distribution depreciation rates are based on one composite rate for all distribution plant rather than by FERC account as are those for Cambridge and Commonwealth (Exh. NSTAR-CLV-9; Exh. DTE-1-25, compare Attachment DTE-1-25-A with Attachment DTE-1-25-B and Attachment DTE-1-25-C). Therefore, the revision of the Boston Edison depreciation rates ensures better matching over the service lives of the assets and that the combination is revenue neutral and that neither customers as a whole, nor NSTAR Electric, gains or loses as a result of the merger (Exh. DTE-4-11).

Exhibit NSTAR-CLV-9 sets forth the development of the depreciation accruals for all three electric companies at the functional levels using the old depreciation rates as applied to the test-year-end plant balances filed in D.T.E. 05-85 (Exh. NSTAR-CLV-1, at 29). The combined Companies' depreciation accruals at each of the functional levels are the dollar level basis on which new depreciation rates are formulated (id. at 29-30). Exhibit NSTAR-CLV-10, pages 1 (revised) and 2 set forth the development of the new depreciation rates for NSTAR Electric at the account and functional levels according to the methodology described further below (id. at 30). Page 1 of Exhibit NSTAR-CLV-10

[10] Indeed, the depreciation expense is revenue-neutral and predicated upon base rates that will remain in effect until approximately 2012, at which time NSTAR Electric may file a rate case (Tr. 4, at 520-522) Any change in rates as a result of such a rate case would require a new depreciation study, which would be subject to extensive Department review (see id.). Therefore, the proposed merger of the Companies does not alter the depreciation expense and customers are unaffected by the change (see id.).

(revised) shows the summary results (id.). Page 2 of Exhibit NSTAR-CLV-10 provides a special analysis in developing the new depreciation rates for the General Plant — Leasehold Improvements (id.). The special analysis is undertaken to show the results of amortizing these facilities over the remaining life of their respective leases (id.). Exhibit NSTAR-CLV-11 sets forth the depreciation study that calculated annual depreciation accruals relating to the consolidated NSTAR Electric Plant filed by John J. Spanos, NSTAR Electric's depreciation expert, as Exhibit NSTAR-JJS-3 (of Exhibit NSTAR-1) in D.T.E. 05-85 (id.; Tr. 4, at 460-461). The depreciation accrual rates for each distribution plant account from this study were used as the starting basis for determining the consolidated NSTAR Electric distribution plant account accruals as of June 30, 2005 (Exh. NSTAR-CLV-1, at 30).

The procedures used were used to develop the new rates to achieve expense neutrality at the functional level (Exh. NSTAR-CLV-1, at 30). The Companies used three functional levels of depreciation: Intangible Plant, Distribution Plant and General Plant (id.). The Transmission Plant functional level is excluded, since approval of any changes to transmission depreciation rates are subject to the jurisdiction of FERC (id.). Currently, all intangible plant (computer software) for all companies is amortized at a rate of 20 percent (five-year amortization) (id. at 31). No change in the depreciation rates for the combined companies was required to remain expense neutral (id.).

Distribution Plant is by far the largest element of depreciation expense contained in retail distribution rates (Exh. NSTAR-CLV-1, at 31). The first step in developing an expense-neutral, unified depreciation rate for Distribution Plant was to determine the annual depreciation accrual using the old rates (id.). The balance by each FERC Plant

Account (Accounts 360–373) as of June 30, 2005 was multiplied by the current depreciation rates in effect for each company (id.). The total of these calculations for all companies was used to determine the annual accrual to be used after the application of the new depreciation rates (id.; see Exh. NSTAR-CLV-9). The combined accrual rates for distribution plant were based on the depreciation study performed by NSTAR Electric in D.T.E. 05-85 and included as Exhibit NSTAR-CLV-11 (Exh. NSTAR-CLV-1, at 31). All of the individual accrual rates for Distribution Plant from the above were reduced by 4.9970 percent so that the total depreciation expense under the combined rates approximately equals the depreciation expense using the old rates for this functional group (Exh. NSTAR-CLV-1, at 31; Exh. NSTAR-CLV-10 (revised)). Compare the combined annual accrual for Distribution Plant of $89,648,551 on Exhibit NSTAR-CLV-10 with the sum of the three companies, $89,648,551, set forth in Exhibit NSTAR-CLV-9 (Exh. NSTAR-CLV-1, at 31-32).

NSTAR Electric proposes to implement amortization rates on General Plant that are consistent with the depreciation study as adjusted for the requirements of the terms of the Settlement Agreement approved by the Department in D.T.E. 05-85 (Exh. DTE-4-1). The first step in the process of developing new depreciation rates for General Plant was to determine the annual depreciation accrual using the old rates (Exh. NSTAR-CLV-1, at 32). The balance by each FERC Plant Account (Accounts 390–398) as of June 30, 2005 was multiplied by the current depreciation rates in effect for each company. The total of these calculations for all companies was used to determine the annual accrual to be used after the application of the new depreciation rates (id.; Exh. NSTAR-CLV-9). The new rates were developed in two phases (Exh. NSTAR-CLV-1, at 32). The first phase involved developing rates for the individual sub-account of Account – 390 Leasehold Improvements, so that the rates match the lives in the terms of the lease (id.). The second phase is similar to what was done to depreciation plant (id.). The depreciation rate for all the remaining accounts equals the proposed depreciation rate in the study multiplied by a factor (49.7437 percent) to ensure revenue neutrality (id.; Exh. NSTAR-CLV-10 (revised)).

The calculations involved in determining the rates for leasehold improvements are a part of Account 390 General Structures (Exh. NSTAR-CLV-1, at 33). Boston Edison currently has five major leased facilities that are currently being depreciated at a rate of 2.76 percent (id.). The proposal is to amortize these facilities over the remaining life of their individual leases, thereby more appropriately matching expense with the expected life and use of these facilities (id.; Exh. NSTAR-CLV-10, at 2).

The Companies are proposing a new method of recording depreciation for General Plant to change the accounting treatment for their investment in general plant equipment from depreciation to amortizable property (Exh. NSTAR-CLV-1, at 33). The proposal is to adopt the terms of FERC Accounting Release No. 15 (AR-15) (id.). FERC adopted this accounting procedure in 1997 for high volume – low dollar value accounts (id.). Under this approach, additions are grouped by vintage and amortized over a pre-determined period of time (id.). The specific accounts that the Companies propose to include are:

- Account 391 — Office Equipment
- Account 393 — Stores Equipment
- Account 394 — Tools & Work Equipment
- Account 395 — Laboratory Equipment

- Account 397 — Communications
- Account 398 — Miscellaneous Equipment

(Exh. NSTAR-CLV-1, at 33-34). This method was recommended in the recent depreciation study (see, e.g., Exhibit NSTAR-JJS-1, pages 21-22, filed in D.T.E. 05-85; (Exh. NSTAR-CLV-1, at 33-34). The resulting depreciation rate for the existing plant in these accounts (excluding computer equipment) is approximately 7.50 percent (Exh. DTE-4-1). This rate is based on the estimated remainder of the original 15-year life adjusted to ensure it remains expense neutral (id.). All new additions to General Plant in these accounts will be amortized by vintage year over a 15-year life (id.; Exh. NSTAR-CLV-1, at 35). This change in depreciation rates does not result from the change to vintage-year accounting (Exh. DTE-4-1). Rather, it results from the comprehensive analysis of depreciation within the overall depreciation study and the requirements of the Settlement Agreement (id.).

The Companies seek this change because the assets in these accounts comprise a very high number of property retirement units, but constitute a very small percentage (1.5 percent) of total plant investment (Exh. NSTAR-CLV-1, at 34). The items in these accounts are relatively inexpensive and because of their size and mobility are very difficult to follow (id.). For example, these accounts would include desks, chairs, radios, cafeteria equipment, and other similar items (id.). If items break or are not useful, the fact is often not reported, which makes retirement accounting difficult (id.). Amortization would reduce the records added, retired and maintained in the General Ledger and Property Records Systems, thereby reducing the time consumed for document preparation, data entry, computer processing, property unit listings and inventorying of equipment (id.). The reduction of the effort on these plant accounts would permit resources to be devoted to the plant accounts with the larger investment (id.). The Department has previously approved this method of accounting applied by NSTAR Gas in D.P.U. 91-60:

> The Department also accepts for purposes of this proceeding the Company's accounting change, for general plant equipment in accounts 391 through 398 and distribution plant equipment in account 387 as amortizable, rather than depreciable, property.

D.P.U. 91-60, at 3.

Under the proposal individual retirements would not be recorded (Exh. NSTAR-CLV-1, at 35). If retirements must be recorded, all the advantages of changing to amortization described above are lost and the Companies would continue to depreciate these assets (id.). Of course, when assets for a particular vintage year have been fully amortized, both the asset and the reserve would be removed from the books (id.). For currently existing assets in these accounts, the depreciation rates will be the rates set forth in the depreciation study filed as Exhibit NSTAR-JJJ-3 in D.T.E. 05-85 (Exhibit NSTAR-CLV-11), multiplied by a factor of 49.7437 percent, as described above (Exh. NSTAR-CLV-1, at 35). The amortization periods for new assets placed in the general plant accounts in question will be 15 years, with the exception of computer equipment, which is five years (Exh. NSTAR-CLV-1, at 35).

G. Service Quality Indices

Although Boston Edison, Cambridge and Commonwealth have already merged operations, they continue to report service quality performance on a company-by-company basis as required by the Department (Exh. NSTAR-CLV-1, at 36). See Department Order on NSTAR Compliance Filing in D.T.E. 99-84 (December 5, 2001). After the formal merger of the companies and the conclusion of the Department's review of service quality standards in D.T.E. 04-116, NSTAR Electric will propose whether and how service quality performance should be consolidated for the merged entity (Exh. NSTAR-CLV-1, at 36).

V. CONCLUSION

For the foregoing reasons, NSTAR Electric has demonstrated that it meets the statutory standard for approval of the merger and requests that the Department approve the Companies' proposed merger pursuant to G.L. c. 164, § 96 and confirm that NSTAR Electric, as the surviving corporation of the merger, will retain all the franchise rights and obligations that were previously held by Boston Edison, Cambridge and Commonwealth and that further action, pursuant to G.L. c. 164, § 21, is not required to consummate the merger.

Respectfully submitted,

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CAMBRIDGE ELECTRIC LIGHT COMPANY
COMMONWEALTH ELECTRIC COMPANY
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